The impact of operating reserves in generation expansion planning with high shares of renewable energy sources

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1. Introduction

System simulations and real-life experience show how a high share of Renewable Energy Sources for Electricity (RES-E) challenges the cost-efficient and reliable operation of the power system [1]–[3]. The variable nature of wind power and PV results in limited controllability and predictability. Consequently, this requires increased operational flexibility, i.e. capacity which can be rapidly regulated up – or downward, in order to keep the total injection in balance with the off-take [4]. This real-time system balance is a prerequisite for stable frequency levels and system security. Unpredicted output deviations caused by variable RES-E (VRES-E) add up to historic imbalance drivers such as equipment outages and forecast errors on demand, thus increasing the system's need for flexibility [5]. Transmission System Operators (TSOs) contract reserve capacity to guarantee sufficient operational flexibility in the real-time to cover for system imbalances [6]. Consequently, the massive increase of VRES-E to substantially impact the operating reserve requirements, and subsequently the RES-E integration costs [7]. Current state-of-the-art in dealing with these reserve requirements considers improved statistical methods for the sizing and allocation of operating reserves, implementing dynamic reserve requirements, and allowing the participation of new technologies [8].

Short-term power system models, typically unit commitment and economic dispatch models integrating reserve requirements, are used to calculate the operational costs of reserve requirements following RES-E integration. In contrast, long-term power system models focus on the impact of RES-E on the future power system generation and transmission assets [9]. They are used to solve the Generation Expansion Planning (GEP) problem by taking into account future investment and de-investment costs. A GEP model attempts to identify the most optimal generation portfolio to meet demand, given a set of objectives and considering several types of uncertainty and reliability constraints [10]. In order to deal with the challenges of the integration of VRES-E, GEP models need to be able to deal with the variability and uncertainty of this generation source.

GEP models may capture different types of uncertainty: Pereira & Saraiva (2008) consider the uncertainty of future demand and market prices [10]. Yaghooti et al. (2010) and Aghaei et al. (2014) investigated the uncertainty introduced by random power plant or transmission line outages [11], [12]. Others have considered the uncertainty introduced by the integration of VRES-E. De Jonghe et al. (2011) include a deterministic operating reserve requirement, based on the installed wind capacity [9]. However, this approach does not allow capturing the stochastic nature of VRES-E forecast errors, nor does it distinguish between the different types of reserves. Tigas & Mantzaris (2012) calculate the need for reserve capacity such that a load shedding event can be avoided with a certain probability considering probabilities of VRES-E forecast errors, unit outages, etc [13]. However, the final capacity mix – found using the TIMES model – is supplemented with peak units to meet reliability constraints. This approach does not guarantee that all necessary reserve capacity will be available at the time when it is needed. Also, it might lead to a sub-optimal solution, as the costs of these peak units are only considered after the generation portfolio optimization.

Typically, GEP models consider a less detailed representation of operational constraints, of which the operating reserve needs are a part. However, disregarding these needs or determining the reserve power capacity ex-post can lead to a generation portfolio that might not be designed to deal with the unexpected output variations. This is expected to result in an underestimation of the integration cost of RES-E. Hence, to study the influence of such requirements on the composition of the future generation portfolio, this work focuses on the integration of detailed reserve requirements in a GEP model.

2. Sizing operational reserves

By formulating appropriate operating reserve requirements, a GEP model may deal with VRES-E uncertainty in a more realistic way. In the synchronous area of Continental Europe, the European Network of Transmission System Operators for Electricity (ENTSO-E) drafted a network code, providing recommendations for member states on how to deal with operating reserve requirements. This work will use the definitions and requirements presented in the *Network Code on Load-Frequency Control and Reserves* published on June 28, 2013 [14].

First we review the types of imbalances that have to be considered, according to ENTSO-E, in the process of dimensioning reserves, i.e. 5 types of imbalances are cited [15]:

1. Disturbance or full outage of a Power Generating Module, HVDC interconnector or load
2. Continuous variation of load and generation
3. Stochastic forecast errors of load and VRES-E generation
4. Deterministic imbalances (deviation between load and step-shaped schedules)
5. Network splitting (generally out of the dimensioning of the Synchronous Area)

The expected magnitude and duration of an imbalance caused by one of the above factors, possible mutual dependency of imbalances and imbalance gradients all have to be taken into account when dimensioning the different types of reserves; namely the Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR).

FCR are used to stabilize the frequency after a disturbance or incident in a matter of seconds. The FCR capacity is determined at the level of the synchronous area. In Continental Europe it is 3000 MW, equivalent to the loss of the two biggest nuclear power units. This effort is shared among TSOs according to their weight in the system. Activation occurs automatically (through governors) whenever a FCR provider observes system frequency excursions. The capacity has to be fully available within 30 seconds.

FRR aim to restore the system frequency by restoring the balance in the control area of a TSO, thus relieving the system wide activated FCR. FRR capacity is activated automatically (aFRR) or manually (mFRR), where aFRR has to be fully available within 30 seconds and mFRR typically within 15 minutes. Their activation is triggered by the *Area Control Error*, which is calculated from the deviation between the scheduled and actual power interchange of a control area, corrected for the frequency. ENTSO-E obligates TSOs to use probabilistic sizing techniques, so they can ensure that FRR capacity can cover system imbalances for at least 99% of the time. They must complement this with a deterministic assessment, so that FRR capacity can cover at least the greatest incident that can occur in their area (e.g. the loss of an HVDC interconnector).

RR are the reserves used to restore or support the FRR to be prepared for additional system imbalances. They are typically slower, with full activation times of up to an hour. A TSO is not obliged to contract RR, but can opt for a combined sizing process of FRR and RR e.g. because of economic reasons.

In this work we will only consider the presence of VRES-E as a driver for the need of reserve power. Hence, no FCR requirements are included. Furthermore, alternative imbalance drivers are neglected, such as the demand variability and unexpected power plant outages. This assumes a full correlation of wind and solar power imbalances with other imbalance drivers which is likely to overestimate the VRES-E's operating reserve needs. However, estimates in literature show short-term reserves could go up to 15% and 18% of installed wind power capacity at a 10% and 20% penetration respectively [1]. The influence of neglecting other imbalance drivers is, therefore, expected to become relatively small in systems with high VRES-E penetrations.

Following the methodology of the Belgian TSO ELIA in its ancillary services study [16], the reserve sizing approach is based on FRR. Hence a demand for up- and downward aFRR and mFRR is formulated. aFRR are expected to be fully available within 30 seconds. This means they will have to be spinning reserves (i.e. provided by online units). On the other hand mFRR will be expected to be fully available within 15 minutes. Therefore, mFRR capacity can consist of both spinning and non-spinning reserves (i.e. provided by online units and fast-starting offline units) To determine the relative shares of the automatic and manual FRR of the total FRR demand we will work as follows. Total FRR capacity (aFRR + mFRR) must cover the system imbalance caused by forecast errors in both directions at least 99% of the time. From now on we will refer to a design reliability of

99%. In contrast the fast components of the system imbalance must be covered by aFRR alone. Following the methodology proposed by ELIA these fast components are modelled by the difference between system imbalances of two consecutive quarter hours, which ELIA labels the volatility of system imbalances. Actual aFRR capacity will then cover a certain share of this volatility. A visualization based on a fictional example is shown in Figure 1.

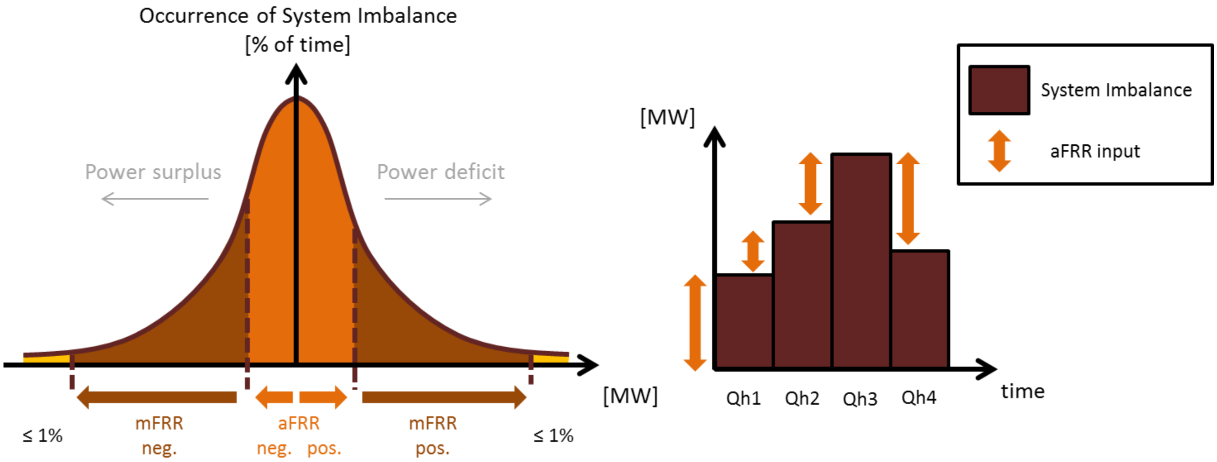

Figure 1: FRR dimensioning - fictional example based on ELIA methodology

To formulate actual reserve power requirements we must overcome another hurdle. The absolute magnitude of a system imbalance caused by a forecast error obviously depends on the installed capacity of VRES-E. Given that we are solving an investment problem this capacity is not known beforehand. We solve this issue by using a normalized Probability Density Functions (PDF). For each type of VRES-E (wind power and PV in the case of this work) a normalized PDF has to be derived. To do this, VRES-E forecast and real time production data as well as installed capacities are needed. After normalizing the first two w.r.t. the latter, we compare the normalized forecast and real time production data to obtain the normalized forecast error (see Figure 2). Then, describing the normalized forecast error in a separate Gaussian distribution for each VRES-E type, we arrive at the normalized PDFs. Using these we can express the reserve power requirements as a percentage of the installed VRES-E capacity, as we will do in the section describing the data and assumptions.

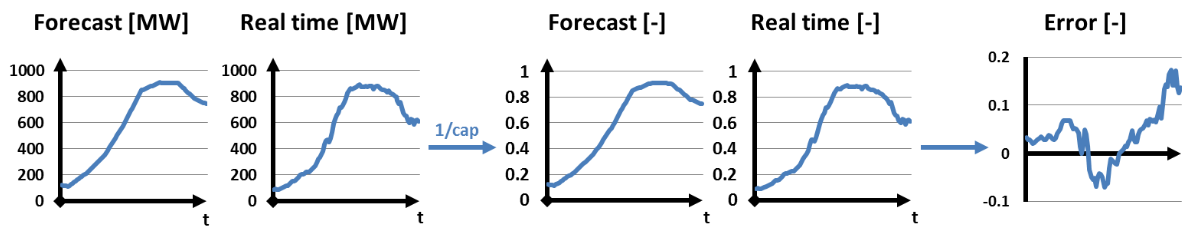

Figure 2: Deriving the normalized forecast error

A couple of things should be noted here. Firstly, the methodology presented here describes a static reserve sizing process, meaning that the demand for reserves is independent of time. This process could be made dynamic, e.g. by reevaluating the demand for reserves on a day-ahead basis, making it dependent on the forecasted output of VRES-E. A dynamic reserve strategy can lead to a significant reduction of both upward and downward reserve capacity, allowing for a more efficient exploitation of the power system [17]. However, as reserve power is still commonly contracted on an annual basis through a static sizing process, we will also limit ourselves to such an approach.

Secondly, we do not benefit of the possible coincidence of wind power and PV forecast errors. To do so the non-normalized PDFs of wind and solar PV should be convoluted. There are two ways to achieve this. One way is by convoluting the non-normalized PDFs beforehand. This would require the installed capacity of VRES-E to be known in advance, which is obviously not the case for an investment model. The other way would be by performing the convolution during the investment optimization. As this is a non-linear operation, we cannot include it in our linear investment model, thus excluding also this possibility. Therefore the need for reserves will to a certain extent be overestimated.

Finally, having derived the normalized PDFs in such a way as is presented above, we assume that the PDFs – or at least their foothills – are independent of the installed capacity. One could argue that, as installed VRES-E capacity increases, forecast errors increasingly average out, thus reducing the relative need for reserve capacity (MW reserve power per MW installed VRES-E capacity). The reserve capacity resulting from this investment model might then again present a certain overestimation. The influence of this assumption is hard to predict and deserves to be the subject of further analysis.

3. Model description

To investigate the impact of reserve requirements within investment models, a generation expansion planning model has been developed. It calculates the optimal installed generation capacity of a system by means of a linear total cost minimization algorithm. To consider the operational costs and constraints a new clustered formulation of the unit commitment problem is used [18]. Firstly, we discuss the objective function and all costs considered. Secondly, we discuss the system constraints, which include the balance equation, the constraints on VRES-E curtailment and load shedding, as well as the detailed reserve requirements. Finally we present the technological constraints. These include a set of logical conditions, the generation limits, minimum up and minimum down time constraints, a set of ramping limits and the provision of aFRR and mFRR by means of spinning and non-spinning reserves. All variables in this model are positive.

Objective function

The objective function represents the annual system cost, aggregating all investment costs (direct investment costs C_{INV} [€/MW] and fixed operating & maintenance costs C_{FOM} [€/MW]), all operational costs (fuel costs C_{FUEL} [€/MWh], variable operating & maintenance costs C_{VOM} [€/MWh], ramping costs C_{RAMP} [€/MWh] and the start-up costs C_{SU} [€/MW]) and the costs of curtailment VOC [€/MWh] and load shedding $VOLL$ [€/MWh]. Minimizing this function will result in the optimal installed capacities $cap(g)$ and $cap(r)$ and hourly generation levels $gen(g,t)$ and $gen(r,t)$, with g and r the sets of conventional and VRES-E generation technologies respectively. Thus, i.e. the model considers both the investments and the scheduling of generation and reserve power. The real time dispatch is not considered, meaning certain costs, e.g. the activation cost of reserves, are not taken into account. Note that start-up costs are directly proportional to the power to which a unit starts up. No distinction is made between hot, warm or cold start-ups.

$$
\begin{aligned}
min\Bigg(& \sum_{g} \big(C_{INV}(g) + C_{FOM}(g)\big) \cdot cap(g) \\
& + \sum_{g,t} \big(C_{FUEL}(g) + C_{VOM}(g)\big) \cdot gen(g,t) \\
& + \sum_{r} \big(C_{INV}(r) + C_{FOM}(r)\big) \cdot cap(r) \\
& + \sum_{r,t} \big(C_{FUEL}(r) + C_{VOM}(r)\big) \cdot gen(r,t) \\
& + \sum_{g,t} C_{RAMP}(g) \cdot \Big(ramp_{up}(g,t) + ramp_{dn}(g,t)\Big) \\
& + \sum_{g,t} C_{SU}(g) \cdot ramp_{su}(g,t) + \sum_{r,t} VOC \cdot curt(r,t) \\
& + \sum_{t} VOLL \cdot ls(t) \Bigg)
\end{aligned}
\tag{1}
$$

System constraints

The first system constraint is the balancing equation which ensures that the supply equals the demand $DEM(t)$ in every time step. Load shedding is allowed and captured by the variable $ls(t)$.

$$\forall\, t \qquad \sum_g gen(g,t) + \sum_r gen(r,t) = DEM(t) - ls(t) \qquad (2)$$

The potential output of the VRES-E is driven by weather conditions. A normalized feed-in profile $VRES(r,t)$ is exogenously determined per type of renewable generation technology r. Curtailment $curt(r,t)$ is allowed and limited to the maximal potential VRES-E generation in every time step.

$$\forall\, r,t \qquad gen(r,t) + curt(r,t) \leq VRES(r,t) \cdot cap(r) \qquad (3)$$

Similarly the amount of load shedding $ls(t)$ is limited by the electricity demand.

$$\forall\, t \qquad ls(t) \leq DEM(t) \qquad (4)$$

As explained in section 2, only aFRR and mFRR are considered. For each reserve category a static need for up - and downward reserves provided with conventional power plants is determined; namely Q_{AFRR}^{UP}, Q_{AFRR}^{DN}, Q_{MFRR}^{UP} and Q_{MFRR}^{DN}. Due to the required speed of aFRR activation, it can be provided exclusively by spinning reserves, captured in the variables $res_{afrr}^{up}(g,t)$ and $res_{afrr}^{dn}(g,t)$. In contrast, upward mFRR can be provided by spinning reserves $res_{mfrr,s}^{up}(g,t)$ and non-spinning reserves $res_{mfrr,ns}^{up}(g,t)$. Downward mFRR can be provided via spinning reserves $res_{mfrr,s}^{dn}(g,t)$ and other online units that can shut down sufficiently fast $res_{mfrr,ns}^{dn}(g,t)$.

$$\forall\, t \qquad \sum_g res_{afrr}^{up}(g,t) \geq Q_{AFRR}^{UP} \qquad (5)$$

$$\forall\, t \qquad \sum_g res_{afrr}^{dn}(g,t) \geq Q_{AFRR}^{DN} \qquad (6)$$

$$\forall\, t \qquad \sum_g \left(res_{mfrr,s}^{up}(g,t) + res_{mfrr,ns}^{up}(g,t)\right) \geq Q_{MFRR}^{UP} \qquad (7)$$

$$\forall\, t \qquad \sum_g \left(res_{mfrr,s}^{dn}(g,t) + res_{mfrr,sd}^{dn}(g,t)\right) \geq Q_{MFRR}^{DN} \qquad (8)$$

Technological constraints

The technological constraints are typically defined at power plant level. To avoid the use of integer variables, these constraints have been reformulated towards the technology level, whereby they deviate from the typical formulations in Mixed Integer Linear Programming Unit Commitment models [19]. Therefore a set of logical conditions has to be introduced (9), (10), (11), (12). First the number of online plants per technology $n(g,t)$ is limited to the available number of plants per technology $N(g)$. This number can be found by dividing the installed capacity $cap(g)$ by $P_{MAX}(g)$, where $P_{MAX}(g)$ is a typical unit size for generation technology g. $P_{MAX}(g)$ is used to derive $N(g)$ from $cap(g)$. $n(g,t)$ is a continuous variable.

$$\forall\, g,t \qquad n(g,t) \leq N(g) = \frac{cap(g)}{P_{MAX}(g)} \qquad (9)$$

Equation (10) establishes a link between the evolution in the number of online units over time and the number of start-ups $n_{su}(g,t)$ and shut-downs $n_{sd}(g,t)$. Note that $n_{su}(g,t)$ and $n_{sd}(g,t)$ are also continuous variables.

$$\forall\, g,t \qquad n(g,t+1) = n(g,t) + n_{su}(g,t) - n_{sd}(g,t) \qquad (10)$$

The number of start-ups $n_{su}(g,t)$ and shut-downs $n_{sd}(g,t)$ is limited to the number of remaining offline and online units respectively.

$$\forall\, g,t \qquad n_{su}(g,t) \leq N(g) - n(g,t) \tag{11}$$

$$\forall\, g,t \qquad n_{sd}(g,t) \leq n(g,t) \tag{12}$$

The introduction of the variables $n_{su}(g,t)$ and $n_{sd}(g,t)$ allows us to introduce linear minimum up and down time constraints. Therefore we adjust equations (11) and (12). Equation (13) states that only units that have been offline for at least the minimum down time $MDT(g)$ can start-up again. Similarly, equation (14) states that only units that have been online for at least the minimum up time $MUT(g)$ can be shut down.

$$\forall\, g,t \qquad n_{su}(g,t) \leq N(g) - n(g,t) - \sum_{z=1}^{MDT(g)-1} n_{sd}(g,t-z) \tag{13}$$

$$\forall\, g,t \qquad n_{sd}(g,t) \leq n(g,t) - \sum_{z=1}^{MUT(g)-1} n_{su}(g,t-z) \tag{14}$$

Now we redefine the generation limits. As each unit is restricted to a maximum and minimum generation level, so must the overall generation of the technology to which these units belong. In equation (16) $P_{MIN}(g)$ is the minimum stable generation level for a unit of generation technology g of size $P_{MAX}(g)$.

$$\forall\, g,t \qquad gen(g,t) \leq n(g,t) \cdot P_{MAX}(g) \tag{15}$$

$$\forall\, g,t \qquad gen(g,t) \geq n(g,t) \cdot P_{MIN}(g) \tag{16}$$

Furthermore, a set of ramping limits is introduced. Given that a unit is online and will remain so during the next time step, it can increase or decrease its output by ramping up or down respectively. This corresponds to the variables $ramp_{up}(g,t)$ and $ramp_{dn}(g,t)$. Alternatively, it can be shut down, decreasing its output to zero. This change in output is represented by the $ramp_{sd}(g,t)$. If a unit is offline, it can change its output by starting up, represented by the $ramp_{su}(g,t)$. When considering a technology, rather than a single unit, these effects can play simultaneously to influence a technology's generation level. This is captured in equation (17).

$$\forall\, g,t \qquad \begin{aligned} gen(g,t+1) = gen(g,t) + ramp_{up}(g,t) - ramp_{dn}(g,t) + ramp_{su}(g,t) \\ - ramp_{sd}(g,t) \end{aligned} \tag{17}$$

The ramping variables $ramp_{up}(g,t)$ and $ramp_{dn}(g,t)$ introduced in equation (17) are restricted. Firstly they are limited by the dynamic characteristics of the technology in question, limiting the rate at which a unit can alter its output. $RU(g)$ and $RD(g)$ represent the up- and downward ramping rate respectively of generation technology g expressed as a share of $P_{MAX}(g)$ per time step. We only consider the units that are already online and will stay online during the next time step, as the effects of the other units are captured in the variables $ramp_{sd}(g,t)$ and $ramp_{su}(g,t)$. The variable $ramp_{sd}(g,t)$ is restricted in two ways. First, it must at least be $P_{MIN}(g)$ per unit shutting down, as a unit cannot function below this level. Second it can at most be $RD(g) \cdot P_{MAX}(g)$ per unit shutting down, whereby we assume that a unit's output level cannot change faster when shutting down than during online operation. Similarly for each starting unit $ramp_{su}(g,t)$ must at least be $P_{MIN}(g)$ and may at most be $RU(g) \cdot P_{MAX}(g)$. It is ensured for all technologies that $P_{MIN}(g) \leq RU(g) \cdot P_{MAX}(g)$ and $P_{MIN}(g) \leq RD(g) \cdot P_{MAX}(g)$ so that all technologies can actually start up and shut down.

$$\forall\, g,t \qquad ramp_{up}(g,t) \leq \big(n(g,t) - n_{sd}(g,t)\big) \cdot RU(g) \cdot P_{MAX}(g) \tag{18}$$

$$\forall\, g,t \qquad ramp_{dn}(g,t) \leq \big(n(g,t) - n_{sd}(g,t)\big) \cdot RD(g) \cdot P_{MAX}(g) \tag{19}$$

$$\forall\, g,t \qquad n_{su}(g,t)\cdot P_{MIN}(g) \le ramp_{su}(g,t) \le n_{su}(g,t)\cdot RU(g)\cdot P_{MAX}(g) \tag{20}$$

$$\forall\, g,t \qquad n_{sd}(g,t)\cdot P_{MIN}(g) \le ramp_{sd}(g,t) \le n_{sd}(g,t)\cdot RD(g)\cdot P_{MAX}(g) \tag{21}$$

Next, the increase in output is restricted to the capacity that was not committed in the previous time step, taking into account the operating range of the units that remain online during the next time step. Similarly the decrease in output is restricted to the capacity that was committed on the previous time step, again taking into account the operating range of the units that remain online.

$$\forall\, g,t \qquad \begin{aligned} &ramp_{up}(g,t) \\ &\le \big(n(g,t)-n_{sd}(g,t)\big)\cdot P_{MAX}(g,t) - \big(gen(g,t)-ramp_{sd}(g,t)\big) \end{aligned} \tag{22}$$

$$\forall\, g,t \qquad \begin{aligned} &ramp_{dn}(g,t) \\ &\le \big(gen(g,t)-ramp_{sd}(g,t)\big) - \big(n(g,t)-n_{sd}(g,t)\big)\cdot P_{MIN}(g,t) \end{aligned} \tag{23}$$

<u>*Operating reserves constraints*</u>

Depending on the time scale within which the different reserve types have to be made available, the ramping parameters need to be adjusted. Care also has to be taken to prevent the reusing of already reserved capacity. E.g. the margin for providing spinning upward mFRR $res_{mfrr}^{up}(g,t)$ is reduced by the already contracted upward aFRR $res_{afrr}^{up}(g,t)$. The provision of downward reserves is restricted further by the fact that a number of units $n_{sd,mfrr}(g,t)$ might already be reserved for the provision of downward reserves through shutting down. This generation margin can also not be double booked. Here $RU_{AFCR}(g)$, $RD_{AFRR}(g)$, $RU_{MFRR}(g)$ and $RD_{MFRR}(g)$ represent the adjusted ramping rates.

$$\forall\, g,t \qquad res_{afrr}^{up}(g,t) \le \big(n(g,t)-n_{sd}(g,t)\big)\cdot RU_{AFRR}(g)\cdot P_{MAX}(g) \tag{24}$$

$$\forall\, g,t \qquad res_{afrr}^{up}(g,t) + res_{mfrr,s}^{up}(g,t) \le \big(n(g,t)-n_{sd}(g,t)\big)\cdot RU_{MFRR}(g)\cdot P_{MAX}(g) \tag{25}$$

$$\forall\, g,t \qquad res_{afrr}^{dn}(g,t) \le \Big(n(g,t)-n_{sd}(g,t)-n_{sd,mfrr}(g,t)\Big)\cdot RD_{AFRR}(g)\cdot P_{MAX}(g) \tag{26}$$

$$\forall\, g,t \qquad \begin{aligned} &res_{afrr}^{dn}(g,t) + res_{mfrr,s}^{dn}(g,t) \\ &\le \Big(n(g,t)-n_{sd}(g,t)-n_{sd,mfrr}(g,t)\Big)\cdot RD_{MFRR}(g)\cdot P_{MAX}(g) \end{aligned} \tag{27}$$

The provision of non-spinning upward mFRR is constrained in two ways. First, a unit must provide at least $P_{MIN}(g)$, as it cannot operate below this level. Second, it can provide at most $RU_{MFRR}(g)\cdot P_{MAX}(g)$. Thus, in order not to violate equation (28), only technologies for which $P_{MIN}(g) \le RU_{MFRR}(g)\cdot P_{MAX}(g)$ can participate in the provision of mFRR. This selection can be made more stringent, depending on a TSO's technical requirements. We introduce an equation similar to equation (20) and adjust equation (13) so that units reserved for the provision of non-spinning reserves $n_{su,mfrr}(g,t)$ are not used for an actual start-up.

$$\forall\, g,t \qquad \begin{aligned} n_{su,mfrr}(g,t)\cdot P_{MIN}(g) &\le res_{mfrr,ns}^{up}(g,t) \\ &\le n_{su,mfrr}(g,t)\cdot RU_{MFRR}(g)\cdot P_{MAX}(g) \end{aligned} \tag{28}$$

$$\forall\, g,t \qquad n_{su}(g,t) + n_{su,mfrr}(g,t) \le N(g) - n(g,t) - \sum_{z=1}^{MDT(g)-1} n_{sd}(g,t-z) \tag{29}$$

The provision of downward mFRR by shutting down follows a similar reasoning. Again, a unit must provide at least $P_{MIN}(g)$, as it cannot operate below this level. It can at most provide $RD_{MFRR}(g)\cdot P_{MAX}(g)$. Only technologies for which $P_{MIN}(g) \le RD_{MFRR}(g)\cdot P_{MAX}(g)$ can participate in the provision of mFRR. This selection can again be made more stringent. We introduce an equation similar to equation (21) and adjust equation (14) so that units reserved for the provision of downward reserves through shutting down $n_{sd,mfrr}(g,t)$ are not used for an actual shut-down.

$$\forall\ g,t \qquad \begin{aligned} n_{sd,mfrr}(g,t) \cdot P_{MIN}(g) &\leq res^{dn}_{mfrr,sd}(g,t) \\ &\leq n_{sd,mfrr}(g,t) \cdot RD_{MFRR}(g) \cdot P_{MAX}(g) \end{aligned} \tag{30}$$

$$\forall\ g,t \qquad n_{sd}(t) + n_{sd,mfrr}(g,t) \leq n(g,t) - \sum_{z=1}^{MUT(g)-1} n_{su}(g,t-z) \tag{31}$$

The provision of spinning reserves uses up part of the ramping ability, restricting the margin for actually altering the generation levels. This margin is further reduced by reserving capacity for the provision of downward reserves through shutting down. Therefore, equations (18), (19), (22) and (23) need to be adjusted appropriately as depicted in equations (32), (33), (34) and (35) respectively, concluding the model description.

$$\forall\ g,t \qquad \begin{aligned} ramp_{up}(g,t) + res^{up}_{afrr}(g,t) + res^{up}_{mfrr,s}(g,t) \\ \leq \big(n(g,t) - n_{sd}(g,t)\big) \cdot RU(g) \cdot P_{MAX}(g) \end{aligned} \tag{32}$$

$$\forall\ g,t \qquad \begin{aligned} ramp_{dn}(g,t) + res^{dn}_{afrr}(g,t) + res^{dn}_{mfrr,s}(g,t) \\ \leq \Big(n(g,t) - n_{sd}(g,t) - n_{sd,mfrr}(g,t)\Big) \cdot RD(g) \cdot P_{MAX}(g) \end{aligned} \tag{33}$$

$$\forall\ g,t \qquad \begin{aligned} ramp_{up}(g,t) + res^{up}_{afrr}(g,t) + res^{up}_{mfrr,s}(g,t) \\ \leq \big(n(g,t) - n_{sd}(g,t)\big) \cdot P_{MAX}(g,t) \\ - \big(gen(g,t) - ramp_{sd}(g,t)\big) \end{aligned} \tag{34}$$

$$\forall\ g,t \qquad \begin{aligned} ramp_{dn}(g,t) + res^{dn}_{afrr}(g,t) + res^{dn}_{mfrr,s}(g,t) \\ \leq \Big(gen(g,t) - ramp_{sd}(g,t) - res^{dn}_{mfrr,sd}(g,t)\Big) \\ - \Big(n(g,t) - n_{sd}(g,t) - n_{sd,mfrr}(g,t)\Big) \cdot P_{MIN}(g,t) \end{aligned} \tag{35}$$

4. Data and assumptions

First we determine the reserve capacities needed according to the methodology presented in Section 2. The normalized PDF for wind power and PV is constructed and VRES-E forecast data, real time production data and installed capacities of the Belgian power system for the year 2013 are used [20]. Using these PDFs, the reserve power requirements can be expressed as a percentage of the installed VRES-E capacity:

$$\forall\ t \qquad Q^{UP}_{AFRR} = \sum_{r} \bar{Q}^{UP}_{AFRR}(r) \cdot cap(r) \tag{36}$$

$$\forall\ t \qquad Q^{DN}_{AFRR} = \sum_{r} \bar{Q}^{DN}_{AFRR}(r) \cdot cap(r) \tag{37}$$

$$\forall\ t \qquad Q^{UP}_{MFRR} = \sum_{r} \bar{Q}^{UP}_{MFRR}(r) \cdot cap(r) \tag{38}$$

$$\forall\ t \qquad Q^{DN}_{MFRR} = \sum_{r} \bar{Q}^{DN}_{MFRR}(r) \cdot cap(r) \tag{39}$$

The parameters $\bar{Q}_{AFRR}^{UP}(r)$, $\bar{Q}_{AFRR}^{DN}(r)$, $\bar{Q}_{MFRR}^{UP}(r)$ and $\bar{Q}_{MFRR}^{DN}(r)$ represent the normalized demand for reserves (MW reserve power per MW installed VRES-E capacity). Their values are exhibited in Table 1 for a chosen design reliability of 99%, determining the combined effort of aFRR and mFRR, and a 90% share of system imbalance volatility to be covered by aFRR.

Techn.	$\bar{Q}_{AFRR}^{UP}(r)$	$\bar{Q}_{AFRR}^{DN}(r)$	$\bar{Q}_{MFRR}^{UP}(r)$	$\bar{Q}_{MFRR}^{DN}(r)$
PV	1.4%	1.4%	12.1%	13.3%
Wind	2.9%	2.9%	16.8%	16.5%

Table 1: Normalized demand for reserve capacity in terms of the VRES-E installed capacity

Given these reserve requirements, the GEP model presented in the previous section is now applied to a conceptual system. Four representative conventional technologies are selected, namely a *Nuclear*, *Coal*, *CCGT* (Combined Cycle Gas Turbine) and *OCGT* (Open Cycle Gas Turbine) technology; as well as two VRES-E technologies, namely *PV* and *Wind*. Their technical characteristics are presented in Table 2. These are all based on the report of the Deutsches Institut für Wirtschaftforschung on *Current and Prospective Costs of Electricity Generation until 2050* [21], except for the typical unit size P_{MAX}. Only the relative value of P_{MAX}, P_{MIN} and the ramping parameter matter, all of which are derived from the aforementioned report. The parameters RU, RD, RU_{AFRR}, RD_{AFRR}, etc. are all derived from the ramping parameter, expressed in % of P_{MAX} per minute. *CCGT* and *OCGT* will be allowed to deliver non-spinning reserves and downward shut down reserves.

Techn.	**P_{MAX} [MW]**	**P_{MIN} [%-P_{MAX}]**	**Ramping [%-P_{MAX}/min]**	**MUT [h]**	**MDT [h]**
Nuclear	400	50	2	24	24
Coal	300	50	4	6	4
CCGT	200	50	6	4	1
OCGT	100	10	10	0	0
PV	5	0	100	0	0
Wind	5	0	100	0	0

Table 2: Technical parameters of the generation technologies[1]

The economic parameters of the conceptual system are presented in Table 3. All are derived from the JRC-EU-TIMES model [22], except for all variable operating and maintenance (O&M) costs and the fuel cost of the *Nuclear* technology which are sourced from the work of De Jonghe et al. (2011) [9]. The ramping cost of the *Nuclear* technology is assumed equal to that of the *Coal* technology. The start-up costs are taken as an average of the costs for a hot, warm and cold start-up. A discount rate of 8% is used.

Techn.	**Investment [k€/MW]**	**Fix. O&M [k€/MW]**	**Fuel [€/MWh]**	**Var. O&M [€/MWh]**	**Ramping [€/ΔMW]**	**C_{SU} [€/MW]**	**Life time [years]**
Nuclear	5000	43	10	5	1.3	200	50
Coal	1700	34	26	10	1.3	50	35
CCGT	855	21	43	10	0.25	37	25
OCGT	486	12	66	10	0.66	25	15
PV	895	13	0	0	0	0	30
Wind	1270	27	0	0	0	0	25

Table 3: Economic parameters of the generation technologies[2]

[1] The technical parameters of the *Nuclear*, *Coal*, *CCGT* and *OCGT* generation technologies are based on the parameters of the *Nuclear*, *Coal New SuperC*, *Gas CC* and *Gas GT* technologies of the DIW report respectively.

To ensure a correct correlation between the meteorological data of the load profile and the VRES-E production profiles, the load of the system is represented by the 2013 load profile of the Belgian power system, which is gathered from ENTSO-E. The profile is rescaled such that the system has a peak power demand of 10 GW. This results in an annual consumption of 64 TWh. Cost of curtailment is put at 0 €/MWh. Cost of load shedding is fixed at 10 000 €/MWh.

5. Results

The generation portfolio of this conceptual system is determined for a time period of one year taking hourly time steps. Two main scenarios are compared: (1) without reserve requirements and (2) with reserve capacity requirements as determined in Section 4. In line with current policy requirements, a minimum target is imposed for the share of VRES-E in the supply of electricity demand, meaning that the VRES-E share must at least meet the imposed target, but can exceed this as well. It starts from 0% (equivalent to no target) and is increased in steps of 10% up to a minimum share of 50%.

In Figure 3 and Figure 4, the installed capacities of the different generation technologies are shown for the scenario without and with reserve requirements respectively. In Table 4 we compare the total system cost of the two scenarios. Table 5 and Table 6 look more closely at the installed capacities and reserve requirements. Finally, Table 7 looks at the total VRES-E energy curtailed.

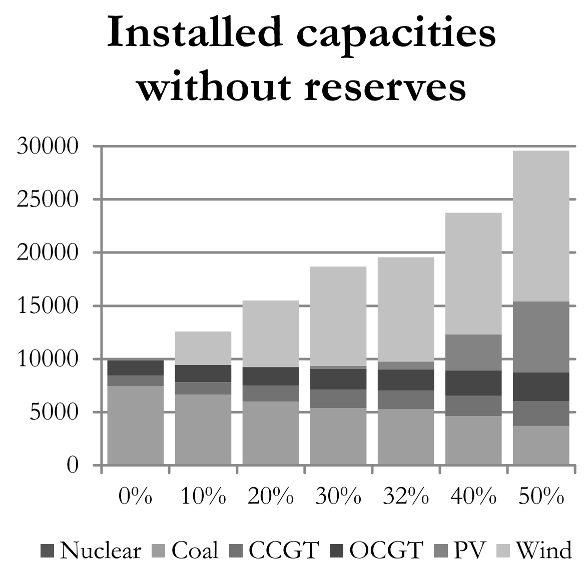

Figure 3: Installed capacities [MW], scenario without reserve requirements, for an increasing target of the VRES-E share in the supply of electricity demand

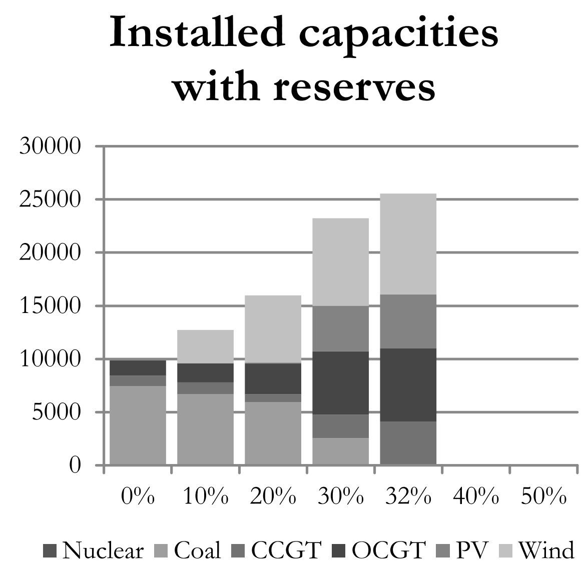

Figure 4: Installed capacities [MW], scenario with reserve requirements, for an increasing target of the VRES-E share in the supply of electricity demand

First of all, no VRES-E capacity is installed when no minimum share (i.e. the 0% target) is imposed, independent of the scenario. All system costs in Table 4 are expressed relative to the system cost of this case, which is the same for both scenarios. Given the used cost data, the VRES-E are thus found to not be competitive in the absence of subsidies. Also, the model never opts to install any *nuclear* capacity. Based on the input data, and in absence of CO_2 costs, the technology appears to be too expensive compared to its alternatives. This result

[2] The economic parameters of the *Nuclear*, *Coal*, *CCGT*, *OCGT*, *PV* and *Wind* generation technologies are based on the parameters of the *Nuclear – 3rd generation LWR planned*, *Hard Coal – Supercritical*, *Natural Gas – Combined-cycle*, *Natural Gas – OCGT Peak device conventional*, *Solar – Solar PV utility scale fixed systems large >10MW* and *Wind onschore – Wind onshore 2 medium (IES class II)* technologies for the year 2020 of the JRC-EU-TIMES model respectively. It is noteworthy that the economical characteristics of the *Solar – Solar PV utility scale fixed systems large >10MW* technology and the *Solar – Solar PV roof 0.1-10 MWp* technology are almost identical (660 €/MW vs. 685 €/MW). The installed capacity of *PV* can thus be seen as a mixture of both technologies. Grid reinforcement costs are not considered in this work.

is in line with the conclusions of the DIW, which shows coal plants to be more economic than new nuclear plants, even when 8000 full load hours are considered [21].

Firstly, results show that operating reserve requirements have a strong impact in the maximum penetration of VRES-E. When neglecting reserve requirements the highest investigated VRES-E target can be met, even though the total installed capacity more than doubles. However, as represented in Figure 4, in case of appropriate reserve requirements, the model cannot be solved for a 40% or 50% target of the VRES-E share. System security constraints thus impede the integration of VRES-E. In fact, a maximum share of VRES-E is encountered, namely 32% of the electricity demand. At this point the requirement for downward reserves prohibits finding a solution to the problem. It imposes a sort of must-run requirement for the conventional generation technologies, which has to be met at every time step of the simulated year. As installed VRES-E capacity increases, so does the demand for downward reserves and with it the must-run requirement or minimum generation level of the conventional generation technologies. At a certain point there is just not enough residual demand left (demand with the conventional generation output subtracted) for the VRES-E technologies to meet the imposed share in the supply of the annual electricity demand. The current way of organizing operational reserves thus imposes a maximum share of VRES-E; one that is clearly lower than what is found when neglecting reserve requirements. Admittedly, this is where our assumption of the independence of the PDFs of the installed VRES-E capacity might come into play, as the model might overestimate the need for reserves at higher VRES-E shares. However, while this might affect the results – i.e. causing the calculated maximum of the VRES-E share to be on the conservative side – it will not overhaul the outcome.

VRES-E target	**0 %**	**10 %**	**20 %**	**30 %**	**32%**	**40 %**	**50 %**
Without reserves	100%	103%	108%	113%	114%	120%	131%
Investment	*39%*	*46%*	*54%*	*60%*	*62%*	*67%*	*74%*
Operation	*61%*	*57%*	*54%*	*53%*	*52%*	*53%*	*57%*
With reserves	100%	104%	111%	129%	137%	-	-
Investment	*39%*	*46%*	*52%*	*53%*	*51%*	-	-
Operation	*61%*	*58%*	*59%*	*76%*	*86%*	-	-

Table 4: System cost for an increasing share of VRES-E in the supply of electricity demand, expressed relative to the situation with a 0% target for the share of VRES-E

Secondly, results show a substantial increase of the total system cost. Table 4 singles out the system cost for the 2 scenarios. The scenario with reserve requirements is more costly than the scenario without reserve requirements. The difference in cost increases as the share of VRES-E increases. Consequently, it is so that a 30% VRES-E system with reserve requirements is almost as expensive as a system where half of demand is met with VRES-E produced electricity and no reserve requirements are considered. While, as can be seen in Table 5 and Table 6, the total installed capacity of both conventional and VRES-E production means is always higher in the scenario with reserve requirements, paradoxically investment costs are lower in this scenario. As installed VRES-E capacity increases, so do the reserve requirements, resulting in a higher need for flexibility. The capital intensive *Coal* technology is replaced by the less capital intensive and more flexible *CCGT* and *OCGT* technologies, resulting in lower total investment costs. Thus, the observed increase in system cost is completely due to the increase in operational costs. While being less capital intensive, *CCGT* and *OCGT* have significantly higher operational costs than the *Coal* technology. As *CCGT* and *OCGT* capacity replaces *Coal* capacity to ensure sufficient flexibility is available, the 2 gas technologies must also meet a larger share of demand, strongly driving up the system cost. This effect also explains the increase of installed *CCGT* capacity. At low VRES-E shares it is relatively modest, as the *Coal* technology can still provide the required downward spinning reserves and presents a cheaper source of electricity supply, whereas the *OCGT* technology can provide the additional required upward flexibility via potential start-ups. At higher shares of VRES-E the *Coal* technology struggles to provide sufficient downward reserves and other technologies have to come online. The *CCGT* technology can provide more flexibility than the *Coal* technology and at the same time produce electricity more cheaply than the *OCGT* technology, explaining why it becomes more interesting as installed VRES-E capacity increases.

In Table 6 the reserve requirements can be seen to increase significantly. The associated must-run requirement for the conventional generation technologies not only prohibits finding a solution for a 40% and 50% VRES-E target, it also causes VRES-E curtailment to increase. At moments when supply exceeds demand, part of the VRES-E output has to be curtailed. In the scenario with reserve requirements more of these moments will occur and more of that output will have to be curtailed as conventional generation output cannot drop below the must-run requirement. Hence, as can be seen in Table 7, curtailment is higher in the scenario with reserve requirements. Incidentally, this is why, for the same installed VRES-E capacity, less VRES-E produced electricity can be used to meet the VRES-E target (as curtailment is not counted). This effect provokes a greater need for installed VRES-E capacity, which causes curtailment to increase (as reserve requirements go up), again provoking a need for more capacity and so on until no solution can be found.

VRES-E target	**0 %**	**10 %**	**20 %**	**30 %**	**32%**	**40 %**	**50 %**
Conventional	9859	9452	9246	9073	9030	8943	8767
Nuclear	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Coal	*7438*	*6648*	*5986*	*5390*	*5254*	*4645*	*3701*
CCGT	*985*	*1183*	*1500*	*1735*	*1769*	*1880*	*2352*
OCGT	*1436*	*1621*	*1760*	*1948*	*2007*	*2418*	*2714*
Variable RES-E	0	3120	6243	9626	10541	14816	20806
PV	*0*	*0*	*0*	*271*	*712*	*3359*	*6651*
Wind	*0*	*3120*	*6243*	*9355*	*9829*	*11457*	*14155*

Table 5: Installed capacities [MW], scenario without reserve requirements, for an increasing target of the VRES-E share in the supply of electricity demand

VRES-E target	**0 %**	**10 %**	**20 %**	**30 %**	**32%**	**40 %**	**50 %**
Conventional	9859	9611	9573	10718	10987	-	-
Nuclear	*0*	*0*	*0*	*0*	*0*	-	-
Coal	*7438*	*6676*	*5920*	*2545*	*0*	-	-
CCGT	*985*	*1119*	*758*	*2204*	*4080*	-	-
OCGT	*1436*	*1816*	*2895*	*5969*	*6907*	-	-
Variable RES-E	0	3120	6409	12530	14571	-	-
PV	*0*	*0*	*89*	*4276*	*5093*	-	-
Wind	*0*	*3120*	*6320*	*8254*	*9478*	-	-
Upward reserve	0	614	1256	2204	2556	-	-
aFRR	*0*	*90*	*183*	*299*	*345*	-	-
mFRR	*0*	*524*	*1073*	*1905*	*2211*	-	-
Down. reserve	0	605	1239	2231	2589	-	-
aFRR	*0*	*90*	*183*	*298*	*345*	-	-
mFRR	*0*	*515*	*1056*	*1933*	*2244*	-	-

Table 6: Installed capacities and reserve requirements [MW], scenario with reserve requirements, for an increasing target of the VRES-E share in the supply of electricity demand

VRES-E target	**0 %**	**10 %**	**20 %**	**30 %**	**32%**	**40 %**	**50 %**
Without reserves	0.00%	0.00%	0.01%	0.40%	0.60%	1.85%	5.37%
With reserves	0.00%	0.00%	0.39%	2.99%	6.16%	-	-

Table 7: Curtailment expressed relative to total demand, for an increasing share of VRES-E in the supply of electricity demand

6. Conclusions and future work

The main contribution of this work is the optimization of a generation portfolio with a high share of renewables and detailed operating reserve requirements, via a new GEP model. The results presented above show that the integration of VRES-E will be more challenging than previously thought, if system security is to be maintained. By including reserve requirements a theoretical maximum for the share of VRES-E that can be integrated in a system is witnessed. Certain elements might increase this maximum penetration level such as better sizing and allocation strategies, e.g. PDF convolution, improved forecast data, etc. However, VRES-E integration clearly proves to be more challenging than what has been found by models that do not incorporate appropriate operating requirements.

In addition, ignoring reserve requirements can result in a generation portfolio that is not capable of dealing with the imbalances caused by VRES-E forecast errors. This may impose a serious reliability threat. Even determining reserve capacity ex-post might lead to such issues, as having adequate reserve capacity does not in itself ensure that this capacity will be available at the time it is needed. By postulating that the reserve power has to be available at every time step of the simulated period, this concern is now dealt with.

Furthermore, neglecting reserve requirements leads to an underestimation of the total system integration cost. In the scenario with reserve requirements more conventional and renewable generation capacity has to be installed. Paradoxically, this does not increase the investment costs. The effect of the increase in installed capacity is undone by the fact that the capital intensive *Coal* technology is replaced by the less capital intensive *CCGT* and *OCGT* technologies, resulting in lower investment costs than in the scenario without reserve requirements. This means, however, that the cost of producing electricity goes up significantly. To such an extent even that the increase in operational costs in the scenario with reserve requirements causes the total system cost to surpass that of the scenario without reserve requirements.

The results suggest that the organization of operational reserves will have to be reconsidered if we are to achieve a VRES-E penetration with an order of magnitude of 50% or higher while keeping system reliability comparable to current standards. Where the scenario without reserves can be seen as a best case scenario, our scenario with reserves could be seen as a worst case scenario. Other reserve sizing strategies could offer a way of raising the maximum VRES-E share. Making the contracting of reserves dynamic rather than static and dependent on forecasted VRES-E output will relax the must-run requirement of the conventional generation technologies at many moments of the year. However, while allowing for a more efficient operation of the system, lower reserve requirements will be linked to lower (forecasted) VRES-E output. This means that the must-run issue will persist when a high VRES-E output is expected, suggesting that this will only be part of the solution.

An important emphasis will have to be put on other (new) types of flexibility. The VRES-E technologies could participate themselves in the offering of reserve power, especially for the downward reserves. This could significantly relax the must-run requirement for the conventional generation technologies, while also allowing a greater integration of VRES-E produced electricity. Nevertheless, this would not completely resolve the must-run issue as currently only part of the installed VRES-E capacity can actively partake in a reserve market. E.g. residential PV, representing an important share of presently installed VRES-E capacity in Belgium and many other European countries, is – for now – not equipped to do so.

As the share of conventional production means diminishes in the power system, still other technologies will have to take over their role in terms of system services. Certain types of demand response and storage technologies could provide the required fast increase/decrease in power. E.g. pumped hydro units can store VRES-E produced electricity and dispatch it in accordance with system requirements, thus simultaneously meeting reserve requirements and increasing VRES-E integration. Interconnection with other regions will cause certain forecast errors to even out, again reducing the need for reserve power driven by VRES-E. It also allows sharing reserve power efforts between regions.

Future work will look into the diversification of reserve power sources, considering also the flexibility offered by the VRES-E technologies themselves, demand response, storage and interconnection capacity. A sensitivity analysis will be performed regarding the stringency of the reserve requirements. Finally, the interest of including the other imbalance drivers in dimensioning the reserves, mainly outages and maintenance, will be examined.

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